Overview

You have opened the first of two files that comprise the contents of Pkg # 22, which was sent to the Board of Commissioners of Public Utilities on September 18, 2001 via a letter from Maureen Greene to G. Cheryl Blundon. The responses to the Requests for Information contained in the attached are listed on the letter, which can be found on page 3 to 51 of this file.

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TRANSMISSION:

Replacement of Insulators - TL229 (69kV Wiltondale - Glenburnie) ($145,000)

Nature of Project
This project involves the replacement of insulators on this 35 km, 25-year-old 69 kV line from Glenburnie Terminal Station to Wiltondale Terminal Station. An insulator inspection and testing program demonstrated deteriorating insulator conditions that will result in mechanical stress failures. This line has a total of 2,100 suspension and 735 post type insulators. This project will
* replace *150* insulators.

Customer Impact
Failure to complete this work could result in the interruption of power supply to Hydro's customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

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RURAL SYSTEMS:

Replace Insulators - South Brook Distribution System($317,000)

Nature of Project
This project involves the replacement of insulators on the South Brook Distribution System. The line on the South Brook Distribution system consists of a 34-year old section from Roberts Arm to Pilley's Island, and a 21-year old section from Pilley's Island to Long Island. Both sections have Canadian Ohio Brass (COB) insulators which are deteriorating with hairline cracks.Hydro has experienced major outages of 20-minute to 21-hour durations affecting anywhere from 173 to 1,283 customers. This line has 1995 suspension and 1,500 pintype insulators. This project
* will replace ***1,420*** insulators.

Customer Impact
Failure to complete this work could result in the interruption of power supply to Hydro's customers.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

RURAL SYSTEMS:

Upgrade - Fuel Storage - Nain ($339,000)

Nature of Project
This project involves the installation of a new liner under the fuel storage tanks, upgrading the dyke walls, upgrading the fuel transfer system, and improving drainage around the perimeter of the site.

This fuel storage site was constructed in ***1974*** and does not meet the current Storage and Handling of Gasoline and Associated Products (GAP) Regulations.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was not required.

Future Commitments
There are no future commitments, this project will be completed in 2002.

GENERAL PROPERTIES:

Purchase Additional Corporate Applications ($517,000)

Nature of Project
This project involves the assessment and purchase of technical and business software. Where a business case warrants, speciality software will be purchased and implemented to address planned business processes.

Hydro must be able to address additional software requirements to support the streamlining, enhancement, and automation of business functions as required during the budget year.

Customer Impact
There is no direct customer impact.

Cost Benefit Study
A formal cost benefit study was ***not*** required.

Future Commitments
There are no future commitments, the project will be completed in 2002.

Newfoundland and Labrador Hydro
Demand and Energy Requirements
Forecast 2001 – 2010[1]
Total Island Interconnected System[2]

Year	MW	GWh
2000 Actual	1443	8057
2001	1576	8240
2002	1602	8316
2003	1611	8384
2004	1632	8479
2005	1652	8560
2006	1673	8639
2007	1696 (Revised)	8734
2008	1719	8831
2009	1735	8894
2010	1741	8929

[1] Source: Long-Term Planning Load Forecast 2001.
[2] Includes load requirements met by Hydro's sources and customers' generation facilities.

Q. Schedule XII of Mr. Budgell's Prefiled Testimony indicates that the 46 MW of Interruptible Load is included in the peak load forecast and used in the determination of LOLH. How is it included in the LOLH determination and how are customers ensured that they are receiving equivalent benefit for the reduced revenue derived from interruptible customers?

A. The 46 MW Interruptible Load is included in the peak load forecast for Abitibi Stephenville (i.e. the 46 MW is not netted off of the Abitibi Consolidated Inc. Stephenville peak load forecast). In Hydro's models of the Island Interconnected System it is treated as a dispatchable resource (subject to the provisions of the contract) available to meet the load of the system. Therefore, when simulating the operation of the system out over time, the value of the contract is reflected in the results of the system simulations.

Please refer to the response to NP-133 for a discussion of the benefit for reduced revenue derived from interruptible customers.

Q. On numerous occasions in the Prefiled Testimony of Hydro's experts, reference is made to the next Rate Application. Mr. Osmond on page 9, lines 4 to 19 of his Prefiled Testimony states that Hydro is not proposing to commence implementation of all of the recommendations in the Board's 1996 Report starting in 2002. Provide the list of recommendations included in the 1996 Report, and indicate which of these recommendations have been implemented, or are proposed to be fully implemented in this application. List the items that Hydro has proposed to address in the next rate application.

A. See attached.

PUBLIC UTILITIES BOARD
REPORT ON RURAL ELECTRICAL SERVICE
JULY 29, 1996

RECOMMENDATIONS	HYDRO'S POSITION/IMPACT
(1) The Board is not recommending any increase in the rates charged in electrically isolated systems, for the first, second or third blocks of energy, nor is it recommending any change in the monthly domestic customer charge of $16.71.	It was Hydro's position at its last rate application in 1992 that the second block should be eliminated and rates in the end block gradually increased. Hydro will address this issue at its next rate application.
(2) The Board recommends that the first block remain unchanged at 700 kWh per month (for domestic customers)	Hydro agrees with this position.
(3) The Board recommends that Hydro prepare a detailed calculation of long run marginal costs. In the event that a detailed estimate of long run marginal cost confirms it to be significantly below the current energy rate, the Board recommends that consideration be given to reducing the energy rate to a level closer to long run marginal costs (for general service customers).	Please see response to NP-184.
(4) The Board recommends that the special general service rate for the first 700 kWh per month, which was established by Order-in-Council in 1989, be eliminated. No change is recommended for the basic customer charge.	Hydro concurs with this recommendation and will address this issue at its next rate application as part of its five year rate implementation plan.
(5) The Board recommends that Hydro be directed to provide a cost benefit analysis of a rate structure for general service customers which provides for a demand charge. The energy and demand charge in such a rate structure should recover long run marginal cost.	Please see response to NP-184

RECOMMENDATIONS	HYDRO'S POSITION/IMPACT
(6) The Board recommends that preferential rates be phased out. The phase out period should be five years.	Hydro concurs with this recommendation. Hydro, at its next rate application, will be addressing this issue as part of its five year rate implementation plan. See recommendation number 7.
(7) The Board recommends that a new rate be designed for federal and provincial departments and agencies and these rates, phased in over five years, should recover full costs (i.e. 100% cost recovery).	Hydro concurs with this recommendation and has in its current rate application before the Board recommended starting the phase out in 2002 and to complete the phase out over a further five year period after Hydro's next rate application.
(8) The Board recommends that both generation assets and the 138 kV transmission line on the Great Northern Peninsula be assigned, on a provisional basis, as being of common benefit to all interconnected customers and that sub-transmission costs (for lines whose voltage is below 138 kV) be specifically assigned. The Board further recommends re-examination of these costs assignment decisions, and the rules for cost assignment, at a future hearing.	Hydro concurs with this recommendation, and has implemented the recommendation in the current rate application.
(9) The Board recommends that the treatment of the Roddickton Woodchip Plant be 100% demand related, as proposed by Hydro.	The Roddickton Woodchip Plant was removed from service with PUB approval in 2000.
(10) The Board recommends that future cost of service reports be generated with six separate studies: (1) Rural Island Interconnected; (2) Newfoundland Light & Power; (3) Island Industrials; (4) Labrador Interconnected; (5) Isolated Island Systems; and (6) Isolated Labrador Systems	Hydro concurs with this recommendation and has included this information in its 2002 Cost of Service Study.

RECOMMENDATIONS	**HYDRO'S POSITION/IMPACT**
(11) The Board recommends that Hydro provide, as part of future cost of service reports, the specific policies as well as an allocation schedule related to operation and maintenance overheads.	Hydro concurs with this recommendation and has included such information in NP-132.
(12) The Board recommends elimination of interest margin on the Hydro Rural Interconnected system and that a rate of return not be allowed on rural electrical assets, as long as the rural system is operating on a deficit basis.	Hydro has excluded these items from its 2002 Cost of Service Study.
(13) The Board recommends that Hydro and Newfoundland Power establish a joint task force to identify measures whereby cost savings can be achieved, both in isolated and interconnected rural systems.	Hydro and Newfoundland Power have held discussions to explore opportunities for co-ordination in an effort to lower the overall cost of providing service to electrical customers on the Island. A Memorandum of Understanding is in place covering the sharing of services and equipment during emergencies.
(14) The Board recommends that independent consultants should be retained to study the isolated systems for the purpose of identifying all possible cost savings and efficiency improvements. The consultant should provide Hydro with targets and with a tracking system by which to measure progress toward achieving these targets.	Hydro does not concur with this recommendation and it does not plan to implement. .
(15) The Board recommends a study of system losses be conducted to improve measurement of station service and line losses.	A field investigation program was implemented to identify metering and reporting deficiencies. Plant metering equipment has been checked and re-calibrated. In addition, new electronic meters have been installed.
(16) The Board recommends an enhanced consumer education	Hydro concurs with this recommendation and has taken

RECOMMENDATIONS	HYDRO'S POSITION/IMPACT
program be undertaken in isolated areas, to promote greater understanding of the costs and operations of the electrical system and the effect of consumer decisions upon electrical loads and costs. Dissemination of information describing the full cost of the electricity they consume would be a major component of such an education program.	action to facilitate this activity by the creation of a Customer Services Department. Increasing consumer education and improving customer service has been a major activity of the Customer Services Department.
(17) The Board recommends each bill should show the full embedded cost of the energy consumed, as well as the amount charged to isolated rural customers.	Hydro has not implemented this recommendation.
(18) The Board recommends design criteria for plant and ancillary equipment should be re-examined, with a view to ensuring reliability requirements are not unduly stringent, particularly in communities operating close to capacity limits.	Please see response to NP-184(d).
(19) The Board recommends tendering practices for fuel should be reviewed, along with the possibility of larger scale purchases and regional storage facilities.	In 1996, Hydro tendered its fuel requirements for a three-year term. The specification was structured in an attempt to reduce fuel costs through large-scale purchases. No competitive advantage was realized as typically each vendor dominates supply in a specific region. Subsequently, in 1999, after reviewing its option Hydro tendered its five-year requirements based on previous practice of tendering prices for individual sites. Hydro continues to evaluate the cost benefit of providing its own regional storage facilities versus leasing from third parties.

RECOMMENDATIONS	HYDRO'S POSITION/IMPACT
(20) The Board recommends an experimental project should be designed by selecting a community facility, such as a school or other public building, in close proximity to a diesel plant, whereby heat from the diesel plant can be recovered. Such a demonstration project might provide a model for research and for subsequent technology transfer.	Hydro initiated a pilot project in 1994 with a church in Mary's Harbour for the sale of waste heat from our diesel plant. The pilot project is in service and a report and recommendations are to be completed in 2001.
(21) The Board recommends alternative technologies should be examined to ensure that all opportunities for cost reduction are fully realized. New technologies for harnessing wind power should be given particular attention.	Hydro continues to monitor alternative technologies for opportunities of cost-effective applications in the isolated diesel areas. However, to date, the most cost-effective and practical supply is diesel generation. In 1997 Hydro participated in a joint study with Newfoundland Power into the potential for mini-hydro in Island Rural Isolated Systems. In 1998, Hydro worked with the Atlantic Wind Test Site (AWTS) in PEI to investigate the integration of wind energy technology at St. Brendans and is currently reviewing a proposal from the AWTS for a wind demonstration project in Ramea.
(22) The Board recommends conservation programs for isolated areas should be designed to defer expansion of capacity and to target for subsidy reduction rather than lower energy use. Demand side management should be directed toward those systems which will soon require capacity expansion.	Please see response to NP-184(e).

Q. Provide a Table which shows the following for each of the years 1994 - 2000 inclusive assuming the implementation of the Cost of Service Methodology approved in the Public Utility Board 1993 Report (where the vertical axis represents the years and the horizontal access the following data):

1. the demand rate which would have been charged the Industrial Customers for firm power and for each class of non-firm service;
2. the energy rate which would have been charged the Industrial Customers for firm power and for each class of non-firm service and for wheeling;
3. the Specifically Assigned Charges which would have been charged Industrial Customers, and the total for all Industrial Customers;
4. the total number of kWh sold to the Industrial Customers for those years for firm power and for each class of non-firm service and for wheeling;
5. the total dollar amount which would have been billed to the Industrial Customers in those years, exclusive of sales tax, for firm power and for each class of non-firm service and for wheeling (indicate subtotals for each class of service and overall total);
6. the average cost per kilowatt hour which would have resulted;
7. the total dollar amount which was billed to Industrial Customers;
8. the average cost per kilowatt hour which was billed to Industrial Customers;
9. the difference between (5) and (7).

A. In response to an Application to the Board by Industrial Customers, Hydro will file the following Cost of Service Studies as a means of meeting the requirements of this request:

(a) 1999 Actual (Rev) - Generic Methodology (Attached)

(b) 2002 Test Year - Generic Methodology (Attached)

The following will be filed as per the agreement reached with Industrial Customers as outlined at the August 29th, 2001 meeting with the Public Utilities Board:

(c) 2000 Actual – Interim Methodology

(d) 2000 Actual – Generic Methodology

(e) 1997 Actual – Interim Methodology

(f) 1997 Actual – Generic Methodology

(g) 2001 Forecast – Interim Methodology

(h) 2001 Forecast – Generic Methodology

The terminology used by Hydro when referring to Cost of Service methodologies is as follows:

Interim Methodology – Methodology as approved in the PUB report dated April 13, 1992. Recommendation 11 of that report states that "Hydro's proposed cost of service methodology be used until it is examined more fully at another hearing".

Generic Methodology – Methodology as approved in the PUB report dated February, 1993. Recommendation 26 of that report states "That the cost of service methodology recommended herein be adopted by Hydro for the purpose of its next rate referral".

Proposed Methodology – Methodology as contained in the Cost of Service Study in the pre-filed evidence of Mr. John Brickhill, Exhibit JAB-1. The proposed methodology is based on the generic methodology adjusted as outlined in the written testimony of Mr. Brickhill.

Q. With respect to forecast 2002 Specifically Assigned Charges for each of the Industrial Customers provide a breakdown of the component parts of each of those forecast Specifically Assigned Charges and identify any Specifically Assigned Charges proposed to be included in 2002 Specifically Assigned Charges which have not been charged in previous years and the dollar amount of and rationale for each proposed change.

A. Please refer to IC-117 for a breakdown of the component parts of each of the 2002 forecast specifically assigned charges.

Specifically assigned charges related to the two frequency converters are the only charges not previously charged to Industrial customers. Please refer to IC-41.1(Rev.2) for the component breakdowns associated with these assets.

The frequency converters were reassigned following a review of plant assignments undertaken in preparation for this rate application. In the initial years of the Island Interconnected System, the frequency converters at Corner Brook and Grand Falls were of benefit to each of the industrial customers, Newfoundland Power and the grid as a whole. With the continued expansion of the transmission system and the construction of generating stations at Cat Arm and Hinds Lake, operation of the frequency converters has little impact on the 230 kV system voltage levels. The role of the frequency converters has been reduced to providing local voltage control for the mill power systems and transferring power from 50 Hz to 60 Hz for use within the individual paper mills. With the frequency converters being only of benefit to the respective customers, the assets were specifically assigned to each of the industrial customers they serve.

Q. Provide a Schedule in the form of Schedule I to the evidence of H.G. Budgell showing each of the years from 1992 to 2002.

A. Please see attached revised page 3 of 3.

Newfoundland and Labrador Hydro

Historical and Forecast System Energy Requirements (GWh)

For 1992 to 2002

Island Interconnected System

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001 F	2002 F
Newfoundland Power	4243.0	4215.4	4200.8	4213.8	4186.6	4306.2	4157.3	4083.8	4263.2	4399.4	4454.8
Hydro Rural Interconnected[1]	300.9	300.5	299.1	286.2	308.8	359.2	361.3	370.5	388.8	398.1	388.9
Corner Brook Pulp and Paper	296.7	253.8	194.4	243.3	311.4	326.0	386.6	313.6	357.8	389.9	506.2
Deer Lake Power[2]	18.1	56.0	17.2	16.5	18.2	19.2	19.5	16.8	18.5	16.9	17.1
Abitibi Consolidated - Grand Falls[3]	154.6	161.5	164.6	178.3	209.3	163.2	90.8	135.4	145.0	177.3	177.3
Abitibi Consolidated - Stephenville	489.4	513.3	530.0	525.2	457.8	497.0	297.1	517.6	537.7	560.0	568.6
Nfld Proc. / North Atlantic Refining	180.4	207.6	108.7	194.6	228.8	244.8	193.7	224.8	219.7	233.6	233.6
Albright & Wilson Americas[4]	7.0	6.7	6.2	2.0	2.6	2.5	-	-	-	-	-
Hope Brook Gold / Royal Oak[5]	41.0	74.5	72.5	70.3	67.2	43.8	-	-	-	-	-
Hydro Auxiliaries[6]	2.5	-	-	-	-	-	-	-	-	-	-
Hydro Sales & Bulk Deliveries[1]	5733.5	5789.2	5593.4	5730.2	5790.8	5961.9	5506.3	5662.6	5930.7	6175.3	6346.4
Transmission Losses	195.3	210.7	224.7	197.0	197.8	202.5	211.4	214.4	210.8	217.2	233.7
Hydro Island Requirement	5928.8	6000.0	5818.2	5927.2	5988.5	6164.4	5717.7	5876.9	6141.5	6392.5	6580.1

1. Hydro Rural data includes distribution losses and sub-transmission losses.
2. Can include Emergency.
3. Can include Emergency.
4. Ceased service in 1998.
5. Ceased service in 1997.
6. Included in Station Services as of 1993.

Newfoundland and Labrador Hydro
Historical System Non - Coincident Maximum Demand (MW)
For 1992 to 2002
Island Interconnected System

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001F	2002F
Newfoundland Power	1032.7	971.0	1027.6	960.5	1034.7	985.0	997.4	963.1	957.2	1014.4	1026.8
Hydro Rural Interconnected[1]	70.7	68.6	69.0	67.8	75.9	81.2	80.2	84.8	82.9	90.9	89.6
Corner Brook Pulp and Paper	43.0	38.0	38.0	38.3	38.2	51.0	54.0	49.0	49.0	51.0	63.0
Deer Lake Power[2]	40.7	46.5	43.2	42.8	40.4	26.5	36.0	23.9	24.4	2.0	2.0
Abitibi Consolidated - Grand Falls[3]	55.8	62.3	63.9	68.8	69.8	66.7	52.9	44.1	45.9	26.0	26.0
Abitibi Consolidated - Stephenville	71.1	71.1	71.1	74.2	72.6	72.6	82.0	71.6	70.4	70.0	71.0
Nfld Proc. / North Atlantic Refining	28.0	29.1	27.6	29.0	31.0	30.8	31.3	30.3	30.3	30.0	30.0
Albright & Wilson Americas[4]	1.4	1.6	1.5	0.6	0.6	0.6	-	-	-	-	-
Hope Brook Gold / Royal Oak[5]	9.6	10.7	11.1	10.6	11.0	10.7	-	-	-	-	-
Hydro Auxiliaries[6]	-	-	-	-	-	-	-	-	-	-	-
Hydro Sales & Bulk Deliveries[1]	-	-	-	-	-	-	-	-	-	1266.1	1291.0
Transmission Losses	-	-	-	-	-	-	-	-	-	50.6	53.2
Hydro Island Requirement	-	-	-	-	-	-	-	-	-	1316.7	1344.2

1. Hydro Rural data includes distribution losses and sub-transmission losses.
2. Can include Emergency. Peak is coincident with CBP&P.
3. Can include Emergency.
4. Ceased service in 1998.
5. Ceased service in 1997.
6. Included in Station Services as of 1993.

Q. Provide the 2002 Forecast Cost of Service with the generation assets, the associated terminal stations and the 138 kV & 66 kV transmission lines on the Great Northern Peninsula assigned as specific to the Rural Interconnected Customers.

A. See attached. This Cost of Service Study has been revised from the original response to incorporate the allocation of transmission losses on the Great Northern Peninsula to Rural. On page 38, Schedule 3.1A, Hydro Rural demand and energy have been increased. Changes resulting from the revised Island Interconnected production demand and energy allocators can be found on pages 39 and 40, as well as on all summary schedules where Island Interconnected customer amounts are reported.

Q. Provide the 2002 Forecast Cost of Service with the generation assets, the associated terminal stations and the 138 kV & 66 kV transmission lines on the Great Northern Peninsula assigned as specific to the Rural Interconnected Customers.

A. See attached. This second revision to the Cost of Service Study originally requested in IC-87 now allocates the distribution substations in Roddickton and St. Anthony to Rural, as referenced in IC-245.

Q. Provide the 2002 Forecast Cost of Service assuming that the Island Interconnected System load factor was 58.14%.

A. See attached. It is important to note that the components of the system load factor – Sales plus Losses and Coincident Peak – were not adjusted. Adjustments to either of these would have consequences, within the Cost of Service, beyond the calculation of system load factor; therefore it is not possible to draw meaningful conclusions from the response to this question.

Q. Provide the 2002 Forecast Cost of Service assuming that the three generating sources referred to in Budgell's evidence page 10, lines 1 B 4 are in service. Use the 2004 forecasted load for the Island Interconnected System.

A. Attached are revised pages of Hydro's Five-Year Plan. The revisions to the plan include:

- The date on the Cover was updated to September 10, 2001.

- The forth last bullet list item in the Executive Summary was revised to reflect the current revenue projection for 2001, i.e. $335 million ($337 million in the prior Plan).

- The Industrial rate after the RSP adjustment presented in Table 8 on page 14 was revised from 35.6 mills to 33.9 mills for 2001.

- The Income Statement (page 16) for 2001 was revised to reflect the combined $11.5 million RSP recovery (previously $13.8 million) and the corresponding amortization of costs in the RSP.

- The Statement of Cash Flows on page 17 was corrected for 2001 to show the combined effect of the plan balance net of the write-off (revised from $65.6 million to $63.3 million) and to show the revised projection for the Industrial collections (revised from $6.1 million to $3.8 million), the end result being no incremental increase or decrease in cash flows.

Q. Provide actual costs for the Island Interconnected system for each of the years 1992 to 2000 inclusive plus the 2001 estimate. Use the same format as in Schedule 1 of J.C. Roberts' evidence.

A. Please refer to the attached table. This revised response incorporates the suggestion from the Industrial Customers, in their Application Affecting Information Requests, dated August 15, 2001, that prorations would be acceptable. Island Interconnected Cost of Service numbers are available for all items on the revenue requirement, with the exception of Lines 18-27 and Lines 32-36. For these amounts, Hydro prorated the Island Interconnected Operating & Maintenance costs, determined by the Cost of Service, over the account group details in the same proportions as Hydro's total revenue requirement. It is important to note that because these amounts have been prorated, they are not supported by detailed financial records.

Cost of Service studies for 1997, 2000, and 2001 are not yet available.

Q. With regard to Brickhill's evidence page 7, lines 1 - 4, list all the changes in assignment on the Island Interconnected System and the cost impact that each change has on the three customer classes.

A. The changes in plant assignment and cost impacts are attached. The impacts for the reassignment of GNP Transmission assets (line 2) have been revised to incorporate the allocation of transmission losses on the GNP to Rural.

NEWFOUNDLAND AND LABRADOR HYDRO
2002 Forecast Cost of Service
Proposed Changes in Plant Assignment - Cost Impacts ($000)

	Before Deficit & Revenue Credit Allocation			After Deficit & Revenue Credit Allocation		
	NP	Industrial	Rural Island Interconnected	NP	Industrial	Rural Island Interconnected
Doyles / Bottom Brook re-assigned from NP to Common	(146)	94	52	(110)	94	---
GNP Transmission assets re-assigned from Rural to Common	7,937	1,459	(9,099)	(10)	1,458	---
Frequency Converters re-assigned from Common to Specific	(130)	141	(11)	(140)	141	---
S'ville / Bottom Brook assets re-assigned from Common to NP	6	(4)	(2)	5	(4)	---

Q. With respect to the diesel units at St. Anthony, Roddickton and Hawkes Bay, what was the average annual revenue from energy generated by each of these units in each of the years since they were interconnected?

A. The annual revenue for St. Anthony, Roddickton, and Hawkes Bay, was determined by dividing the total Island Interconnected revenue by the total Island Interconnected gross production. This number is then multiplied by the gross production for each of the diesel units shown below.

Year	St. Anthony	Roddickton	Hawkes Bay
1996	$45,328	$7,799	$25,860
1997	$11,351	$2,911	$5,715
1998	$18,377	$5,692	$5,389
1999	$10,109	$927	$7,959
2000	$6,320	$0	$2,320

Q. What are the forecast cost implications for the Industrial Customers and Newfoundland Power of the change in assignment of the 138 KV and 66 KV transmission lines and associated terminal station equipment connecting Hawkes Bay, St. Anthony and Roddickton generation from Hydro Rural to Common?

A. The cost implications are as follows:

Newfoundland Power	$10,000	decrease
Island Industrial Customers	$1,458,000	increase

These numbers have been revised from those originally filed to incorporate the allocation of transmission losses on the Great Northern Peninsula to Rural.

A revised Cost of Service study is attached. On page 38, Schedule 3.1A, Hydro Rural demand and energy have been increased. Changes resulting from the revised Island Interconnected production demand and energy allocators can be found on pages 39 and 40, as well as on all summary schedules where Island Interconnected customer amounts are reported.

Q. Q. K.C. McShane (paged 23-24) indicates two reasons for differences regarding Hydro's capital structure as reported in 1999 and the forecast capital structure for the test year 2002. Provide adjusted debt/equity and interest coverages estimates for Hydro's regulated "utility only" operations for each of the years 1992 to 2001 inclusive (indicating each of the components required for the calculation) on a basis consistent with the assumptions adopted for the 2002 test year but based on actual dividends (if any) paid in each year.

A. The attached schedule shows the calculation of Hydro's regulated "utility only" debt/equity ratios which includes IOC.

Please refer to the response to NP-2 for the applicable regulated interest coverage ratios.

Q. **Cost of Service Study (COSS) evidence - Exhibit JAB**

(1) Industrial revenues: Explain the basis for (a) the Industrial - Firm revenue credit of $40,326 in Schedule 1.2, line 4, column 4, and (b) the Industrial - Non Firm Revenues of $381,121 in Schedule 102, line 5, column 2. In each instance, indicate all billing determinants and rates assumed for these estimates.

(2) Industrial -Non Firm costs:

(a) Indicate any cost based rationale for the demand charge of $1.50 per kW proposed for non-firm sales to IC.

(b) Confirm that the COSS provides no analysis of any demand related costs for non-firm sales, and that the costs assigned to this service in the COSS are solely the firm energy cost of $.02311 per kWh. (Schedule 1.3, page 1)

(c) Provide a table setting out the assumed COSS generation (MWh) by source (hydraulic, No. 6 fuel, diesel fuel, gas turbine fuel, power purchases from NUGs, power purchases from non-NUGs) and month for the test year 2002 for the Island Interconnected System. Indicate the likely percent of load supplied by thermal during off-peak hours (low load evenings and weekend hours) during each month.

(d) Indicate annual functionalized cost of service for each of the above generation sources (in (c) above) and for transmission based on COSS for the Island Interconnected System, showing separately for each generation source and for transmission (where this is separate): fuel expenses, O&M, depreciation, expense credits, disposal gain/loss, return on debt and return on equity. Indicate classified generation and transmission costs (Production Demand, Production and Transmission Energy, Transmission Demand) separately for each fuel source and for transmission.

(e) Compare in detail the COSS firm energy cost of $.02311 per kWh and the non-firm energy charge rate as proposed in Schedule A of the Application (page 3), assuming the average cost of fuel assumed for the COSS; indicate how this charge could likely vary by month and time of day, based on the assumptions adopted for COSS as to expected fuel use. Explain how in practice it will be determined what fuel source is used to supply non-firm energy. What will happen if this energy is supplied in whole or in part from non-thermal sources?

(3) Holyrood average capacity factor: Provide, on the same basis as Schedule 4.3, the calculations to indicate the forecast net capacity factor for Holyrood for the year 2002. Explain the factors affecting variances in this capacity factor for the years 1997 through 2002. Assuming that the COSS for 2002 assumes No. 6 fuel consumption based on average hydraulic generation availability and forecasts loads, why would it not be more appropriate to use the net capacity factor consistent with these assumptions rather than one based on the prior 5-year actual average?

(4) Loads used for COSS: Provide a table or the Island Interconnected System test year 2002 setting out for each rate class the following projections: billing demands at customer meter; coincident peak loads at customer meter and at generator (after provision for losses); 2CP kW at customer meter and at generator (after provision for losses); sales at customer meter and generation energy requirements after losses; number of customers for COSS allocation purposes. Explain all assumptions used to derive these projections.

(5) Load Factor classification - generation costs: Review the rationale behind the Board's 1993 Report recommendation for splitting hydraulic plant costs for the Island Interconnected System between energy and demand based on the system load factor. Indicate the change that this creates from the previous COSS adopted by Hydro for the last rate hearing. Indicate the rationale for also applying the load factor of each Isolated Diesel system group in order to split diesel plant costs between energy and demand.

(6) Generation cost allocation: As reviewed in the evidence of J. A. Brickhill (page 8), generation costs for the Island Interconnected System have been allocated among rate classes based on a 2CP allocator. Provide the loss of load hours (LOLH) study carried out by Hydro which supports use of a 2CP allocator because it indicates a greater risk of loss of load hours largely in two winter months. Provide the annual data supporting Schedule II of J. A Brickhill's evidence for each year indicated in this schedule (1994, 1996, 1997, 1998, 1999, 2000); provide the same information for 1995 (if available), projections for 2001, and the numbers supporting the projections for 2002. Indicate any other tests that could reasonably be considered when testing an allocation method in addition to the variation in results over time, and assess the 2CP method in light of each such test.

(7) Changes to rural deficit allocation: L. A Brickhill indicates at page 14 that the method of allocating the rural deficit between customers has changed to reflect the change in methodology from AED-based to CP-based. Indicate the difference in COSS results due to this one change in methodology, and the impact that this change has on allocation of the rural deficit for the 2002 test year.

(8) Changes in RSP allocation: L. A Brickhill indicates at page 15 that the RSP has historically been split between participating customer groups based on Hydro's COSS. Indicate what changes, if any, the current COS methodology makes with respect to such splits compared to the COSS methodology used previously and provide an assessment of the differences if any that result to the test year 2002 RSP allocation as provided for in schedule 1.2.1 of the COSS.

A. (1)(a) The Industrial - Firm revenue credit of $40,326 in Schedule 1.2, line 4, column 4, (Exhibit JAB-1, page 4) was allocated to customer classes based on revenue requirement. The $40,326 was therefore calculated as follows:

Industrial Firm Revenue Requirement Before Deficit and Revenue Credit	$ 50,005,883
Divided by:	
Total Island Interconnected Revenue Revenue Requirement (Excluding Non-Firm Revenue Requirement)	$277,812,814
Equals	18%
Multiplied By	
Total Island Interconnected Non-Firm Revenue Credit	$ 224,033
Equals	$ 40,326

(1)(b) The Industrial - Non Firm Revenues of $381,121 in Schedule 1.2, line 5, column 2 was calculated as shown on the attached Page 11 of 12.

(2) Industrial -Non Firm costs:

a) Please see response to NP-183.

b) The costs assigned to non-firm sales are as detailed in the Island Interconnected schedule showing the allocation of functionalized amounts to classes of service (Exhibit JAB-1, pages 39-40). The $157,088 is comprised of only energy cost allocations. The firm energy cost of $.02311 per kWh was derived from these allocated costs, rather than providing the basis for determining the costs.

c) The table below shows the assumed Cost of Service Generation by source for the test year 2002 for the Island Interconnected System.

Island Interconnected System
Assumed Cost of Service Generation by Source
(MWh)

Month	Hydraulic Plants	Holyrood (No.6 Fuel)	Diesel Plants	Gas Turbine Plants	Power PurchaseNUGs	Other Power Purchase
January	410,410	304,890	30	1,070	11,600	0
February	368,120	275,390	30	240	9,320	0
March	426,860	228,670	30	220	9,920	0
April	353,830	196,700	30	220	11,120	0
May	331,890	152,450	30	220	13,810	0
June	329,580	98,350	30	220	13,320	0
July	408,050	0	30	220	13,000	0
August	401,530	0	30	220	12,820	0
September	273,460	147,530	30	220	12,360	0
October	290,850	203,260	30	220	13,240	0
November	314,300	245,880	30	220	12,870	0
December	362,790	304,760	30	900	12,520	0
Total	4,271,670	2,157,880	360	4,190	145,900	0

While thermal generation is required to complement production from Hydro's hydraulic resources in order to meet the overall system load, its output is varied to maintain system security and for water management reasons.

Normally, thermal generation is base loaded at an efficient output level. Hydraulic generation is used to track the system load. Thermal output may be reduced for system security or for system loading reasons (ie. not enough load to share amongst required on-line generation). As well, thermal output may be increased from its base load to meet system peak requirements.

Each week, System Operations sets the thermal base load requirement to manage the water resource while respecting power system security. The likely percent of loading supplied by thermal generation during off peak hours varies as a result of the items previously mentioned, however, the likely percent of system load supplied by thermal generation in the off-peak hours is 2 to 5 percent higher than the percent of system load supplied by thermal generation in the on-peak hours.

d) This analysis is not currently available, but work is in progress.

e) The following table compares the industrial firm energy charge with the industrial non-firm energy charge by month for 2002. It uses the average cost of fuel used in the cost of service for each source.

Comparison of Industrial Firm Rates and Non-Firm Energy Rates

Month	Firm Energy Rate	Holyrood Non-Firm Energy Rate	Variance from Firm	Gas Turbine Non-Firm Energy Rate	Variance from Firm	Diesel Non-Firm Energy Rate	Variance from Firm
January	$0.02311	$0.04387	$0.02076	$0.10401	$0.08090	$0.10743	$0.08432
February	$0.02311	$0.03914	$0.01603	$0.10278	$0.07967	$0.10743	$0.08432
March	$0.02311	$0.03914	$0.01603	$0.10367	$0.08056	$0.10743	$0.08432
April	$0.02311	$0.03745	$0.01434	$0.10360	$0.08049	$0.10743	$0.08432
May	$0.02311	$0.03745	$0.01434	$0.10354	$0.08043	$0.10743	$0.08432
June	$0.02311	$0.03686	$0.01375	$0.10524	$0.08213	$0.10743	$0.08432
July	$0.02311	$0.03686	$0.01375	$0.10518	$0.08207	$0.10743	$0.08432
August	$0.02311	$0.03686	$0.01375	$0.10514	$0.08203	$0.10743	$0.08432
September	$0.02311	$0.03657	$0.01346	$0.10686	$0.08375	$0.10743	$0.08432
October	$0.02311	$0.03639	$0.01328	$0.10686	$0.08375	$0.10743	$0.08432
November	$0.02311	$0.03620	$0.01309	$0.10683	$0.08372	$0.10743	$0.08432
December	$0.02311	$0.03613	$0.01302	$0.10814	$0.08503	$0.10743	$0.08432

The non-firm energy charge will be at the Holyrood non-firm rate for all periods including the periods when no thermal source is operating, except when either or both of the diesel plants and the gas turbine plants are operated or their output must be increased to meet the non-firm load. Typically the diesel plants or gas turbine plants would be required to meet non-firm energy requirements during peak load periods or when there are transmission restrictions to the area of the grid where the customer is located. Although the higher non-firm rates could apply during any hour of the year due to transmission or generation problems, the probability is higher in the winter period (December to March) and during the peak hours of 0800 to 2000 hours each day.

The decision to use a higher cost source is made by the power system operator when he determines there is insufficient power or energy available from other sources, either hydroelectric or Holyrood to meet the load demanded on the system, or there is insufficient transmission capacity to an area where the non-firm load is being demanded.

(3) The Holyrood net capacity factor for the year 2002 based on the forecast energy production is as follows:

$$\frac{2{,}157{,}880{,}000}{466{,}000 \times 8{,}760} = 52.86\%$$

The capacity factors from 1997 to 2000 are based on the thermal production required in those years. Both hydraulic generation and system load affect the Holyrood net production requirement. In all of these years the hydraulic generation was above average resulting in reduced Holyrood requirements. In addition, in 1998 and 1999 net production at Holyrood was reduced further due to the lower load caused by extended labour disputes in the pulp and paper industry. The capacity factors for 2001 and 2002 are based on forecast net production at Holyrood, which is based on the load forecast for those years with average hydraulic production.

(4) The table requested is shown on the attached page 12 of 12.

(5) At the last rate hearing, hydraulic plant costs for the Island Interconnected System were split on a 50% demand/50% energy basis in the 1992 COS Study.

Diesel plants in the Isolated Systems are operated as base load plants similar to the Holyrood Thermal plant. For this application, Hydro has proposed using the system load factor for the Labrador and Island Isolated Systems as a proxy for capacity factor as used for Holyrood for consistency.

(6) See response to NP-135 for copy of 2CP allocator report. See response to IC-137 regarding data supporting Schedule II of J.A. Brickhill. Other tests which could be reasonably considered are Bonbright's fair-cost-apportionment objective and the consumer rationing objective. The 2CP method meets both. It fairly distributes the generation demand requirement among the Island Interconnected System customers as it reflects cost causality. It promotes the use of economically justified service because it allocates costs to those who cause the incurrence of the costs.

(7) The 1992 test year Cost of Service (COS) methodology used Average and Excess Demand (AED) kW to allocate production and transmission demand costs to rate classes. The proposed methodology uses Coincident Peak (CP) to perform these allocations. The Cost of Service, revised to reflect the AED methodology, is attached.

(8) The 1992 test year Cost of Service (COS) methodology used Average and Excess Demand (AED) kW to allocate production and transmission demand costs to rate classes. The proposed methodology uses Coincident Peak (CP) to perform these allocations. This change in methodology impacts the RSP customer splits, as revised actual energy amounts, using AED methodology, also affected demand costs, and revised demands were therefore also required for the RSP split between customer groups. Schedule 1.2.1 (exhibit JAB-1, pages 9-10) is impacted in that CP kW are also used to determine the unit costs of the deficit. It is important to note that cost allocation also would change if AED were used. This analysis does not

consider those impacts. The effects of allocating the rural deficit (Schedule 1.2.1) using AED on the 2002 forecast annual RSP activity are:

	Proposed	Revised	Difference
Newfoundland Power	$19,380,610	$19,375,272	$(5,338)
Island Industrial	5,909,874	5,909,874	-
Labrador interconnected	199,739	205,077	5,338
	$25,490,223	$25,490,223	-

(f) Please refer to the response to 1(c) above.

(g) Please refer to the response to 1(c) above.

1. Please refer to the response IC-203 1(c) above.

2. Please refer to the response to IC-180.

3. Please refer to the response to IC-87.

4. See attached Interconnection Studies as requested.

6. See IC-203(6) Revised.

Q. **Impacts re: Interconnections of Isolated Rural Systems to Island Interconnected System**

6. In 1995, the Board recommended "that the prudence of costs associated with the St. Anthony/Roddickton interconnection be reviewed at the next Hydro rate referral, following the interconnection, for the purpose of determining recoverable costs." Provide all evidence available to Hydro as to why this interconnection was undertaken, and that the costs were prudently incurred and in the best interest of customers on the Island Interconnected System.

A. 6. The report entitled "Great Northern Peninsula Interconnection Study" dated October 18, 1993 (attached to IC-203(5)) reviewed several interconnection alternatives. The report determined that while technically viable, the interconnection did not meet the minimum economic guideline applied by Hydro Management when approving interconnection projects.

However, early in 1994 the Canada/Newfoundland Infrastructure Initiative was announced and Hydro applied for and was granted $5.0 million to be applied toward the interconnection of St. Anthony/Roddickton system. Analysis indicated that this funding improved the economics of the proposed interconnection and a decision was made to proceed.

The interconnection scheme approved was very similar to interconnection alternative #4 – 138 kV Bear Cove to St. Anthony Airport as outlined in the October 18, 1993 report, with the following changes:

The in-service date had been moved from 1998 to 1996 in order to take advantage of funding under the Infrastructure Agreement;

- The Hawke's Bay diesels were to be relocated to the Roddickton Woodchip Plant;
- The Roddickton woodchip fired thermal generating station was to be modified to burn #2 fuel oil and placed on standby; and
- Switched shunt reactors and capacitors were to be used for voltage control instead of static var compensators.

Subsequent to project approval, the following changes were made to the interconnection concept:

- It was decided to leave the diesel units at Hawke's Bay and not relocate them to Roddickton; and
- It was decided not to convert the Roddickton Woodchip Plant to an oil fired operation.

The interconnection alternative approved had an estimated capital cost of $38.4 million or a net cost of $33.4 million including the $5.0 million Infrastructure grant. A cost effectiveness analysis, which incorporated the Infrastructure grant as well as revised load forecasts, was completed. The revised load forecasts, fuel series and Holyrood incremental energy rates are shown in Schedule 1-3 respectively. The following table summarizes the results of the analysis and copies of the complete cost effectiveness analysis are attached.

SUMMARY OF COST EFFECTIVE ANALYSIS (1993$ X 1000)			
Cumulative Present Worth to 2022		Present Worth Difference at 2011	Payback Period Years
Isolated Alternative	Interconnected Alternative		
88001	73769	-4020	12

Given that the payback period is less than Hydro's minimum economic guideline that interconnection projects must have payback periods not exceeding 15 years, the decision was made to proceed with the project. The project, when completed, cost approximately $31.4 million and with the $5.0 million infrastructure grant resulted in a net cost of $26.4 million.

SCHEDULE 1
GNP INTERCONNECTION ANALYSIS
LOAD FORECASTS

REVISED MAY 1994

Year	St. Anthony/Roddickton System				Existing GNP System Forecast	
	Isolated Forecast		Interconnected Forecast			
	(kW)	(MWh)	(kW)	(MWh)	(kW)	(MWh)
1994	11263	51412	-	-	26791	112545
1995	11539	51922	-	-	27999	117812
1996	11640	52360	-	-	28586	120272
1997	11742	52808	11348	49209	29149	122624
1998	11845	53257	12676	54687	29696	124920
1999	11941	53673	13535	58097	30249	127234
2000	12037	54090	14064	60370	30740	129295
2001	12140	56222	14596	63930	31208	131260
2002	12257	56751	15050	65920	31689	133279
2003	12371	57267	15399	67447	32159	135255
2004	12517	57926	15705	68786	32605	137131
2005	12665	58591	16016	70152	32986	138735
2006	12832	59348	16285	71328	33365	140342
2007	13002	60112	16555	72513	33705	141780
2008	13163	60838	16790	73540	34008	143055
2009	13295	61432	17002	74471	34339	144452
2010	13438	62078	17225	75446	34682	145898
2011	13590	62767	17457	76460	35004	147259
2012	13739	63436	17678	77430	35296	148496
2013	13871	64033	17877	78299	35581	149696
2014	13971	64484	18058	79092	35866	150901
2015	14082	64984	18244	79908	36132	152021
2016	14203	65532	18436	80751	36398	153138
2017	14309	66010	18604	81483	36673	154300
2018	14400	66419	18747	82111	36938	155418
2019	14497	66855	18901	82784	37177	156423
2020	14603	67334	19059	83480	37404	157378
2021	14697	67760	19200	84096	37642	158384
2022	14777	68119	19319	84617	37882	159394

Note: Existing GNP system forecasts include existing loads from Bonne Bay to the Flower's Cove area.

SCHEDULE 2
GNP INTERCONNECTION ANALYSIS
FUEL SERIES

REVISED APRIL 1994

Year	Residual Fuel $/BBL	Diesel Fuel $/L	Wood Fuel $/Tonne
1993	15.4	0.198	29.21
1994	13.8	0.190	29.21
1995	14.0	0.201	29.21
1996	15.2	0.216	29.21
1997	16.4	0.232	32.11
1998	17.6	0.247	32.11
1999	18.9	0.262	32.11
2000	20.2	0.278	32.11
2001	21.8	0.298	36.12
2002	22.5	0.304	36.12
2003	23.1	0.308	36.12
2004	23.9	0.315	36.12
2005	24.3	0.322	40.36
2006	24.8	0.328	40.36
2007	25.3	0.335	40.36
2008	25.8	0.342	40.36
2009	26.3	0.348	45.04
2010	26.9	0.355	45.04
2011	27.4	0.363	45.04
2012	28.2	0.369	45.04
2013	29.8	0.376	49.58
2014	30.6	0.384	49.58
2015	31.6	0.392	49.58
2016	32.5	0.400	49.58
2017	33.5	0.408	54.55
2018	34.4	0.416	54.55
2019	35.3	0.423	54.55
2020	36.3	0.432	54.55
2021	37.2	0.440	60.01
2022	38.2	0.449	60.01

SCHEDULE 3
GNP INTERCONNECTION ANALYSIS
HOLYROOD INCREMENTAL ENERGY RATES

REVISED APRIL 1994

Year	Energy Rate $/kWh
1997	0.0271
1998	0.0291
1999	0.0312
2000	0.0334
2001	0.0360
2002	0.0372
2003	0.0382
2004	0.0395
2005	0.0402
2006	0.0410
2007	0.0418
2008	0.0426
2009	0.0435
2010	0.0445
2011	0.0453
2012	0.0466
2013	0.0493
2014	0.0506
2015	0.0522
2016	0.0537
2017	0.0554
2018	0.0569
2019	0.0583
2020	0.0600
2021	0.0615
2022	0.0631

Note: Assumes a Holyrood efficiency of 605 kWh/Barrel

Q. **NUG cost benefits for ratepayers**:

(1) Indicate the overall cost benefits to ratepayers (through reduced revenue requirements in 2002 and subsequent years) provided by each of the NUGs implemented since 1992.

(2) Indicate the forecast kWh for 2002, and actual numbers for each year to date of operation, of the generation for each NUG during the winter months (January to March and November and December) and the other months (April to October).

(3) Compare mill/kWh costs for each NUG (as set out in Schedule IX to R. J. Henderson's evidence) to costs forecast for existing thermal facilities and for other new generation options available to Hydro.

(4) Explain the basis for setting NUG charges higher in 5 winter months relative to the other months, and indicate the extent to which these differences reflect Hydro's variability in seasonal time-of-use costs.

A. (1) On a go-forward basis, the overall forecast cost benefit to ratepayers provided by Algonquin Power and the Star Lake Partnership for the period from 2002 to 2006 is shown below. The expansion plan beyond 2006 has not been finalized. The total forecast benefit is comprised of an energy component and a capacity component. The energy component is based on avoided thermal energy production including fuel and variable O&M, as produced by Hydro's generation planning model. The capacity component is based on the capital cost of a similar amount of simple cycle gas turbine capacity which is Hydro's least costly capacity alternative. In addition to these direct benefits, other benefits such as reduced emissions from Hydro's thermal plants are also derived from the NUGS contracts.

	(mills/kWh)				
		Algonquin Power		Star Lake Hydro	
Year	Avoided Costs	Project Costs	Variance	Project Costs	Variance
2002	73.5	70.6	2.9	67.9	5.5
2003	64.6	71.2	-6.5	68.5	-3.8
2004	59.0	71.9	-12.9	69.1	-10.1
2005	59.9	72.7	-12.8	69.9	-10.0
2006	63.0	73.5	-10.5	70.6	-7.6

(2) Please refer to table below:

Newfoundland & Labrador Hydro
NUGS Power Purchases

Star Lake Hydro Partnership

Actual	January to March (kWh)	April to October (kWh)	November to December (kWh)
1998	0	3,036,448	23,590,499
1999	35,357,979	79,806,714	23,623,995
2000	36,942,083	81,419,129	24,689,199
Forecast			
2001	29,181,000	76,691,000	22,129,000
2002	29,181,000	76,691,000	22,129,000

Algonquin Power (Rattle Brook) Partnership

Actual	January to March (kWh)	April to October (kWh)	November to December (kWh)
1998	0	112,056	2,502,760
1999	3,796,698	10,449,273	3,130,405
2000	2,997,733	11,431,296	3,397,398
Forecast			
2001	1,650,000	12,980,000	3,270,000
2002	1,650,000	12,980,000	3,270,000

(3) The comparison of mill/kWh costs for each NUG to forecast costs for existing thermal facilities and Granite Canal is shown below. For reasons of commercial confidentiality, Hydro cannot provide similar information for other new generation options available to Hydro.

	Mills/kWh		
	2001	2002	2004
Algonquin Power	69.8	70.6	
Star Lake Partnership	67.3	67.9	
Existing Holyrood[(1)]	52.9	51.0	
Existing Gas Turbine[(1)]	115.6	112.0	
Existing Diesel[(1)]	103.4	100.3	
Granite Canal[(2)]			54.2

[(1)] Costs for existing thermal plant reflect fuel and variable O&M costs
[(2)] Cost for Granite Canal reflects the levelized capital recovery and O&M costs for the first full year of operation.

(4) In the 1992 RFP for non-utility generation from small scale hydro projects, Hydro set a maximum price schedule for proposals whereby proponents could elect to submit those prices or an alternative lower schedule of prices.

Only the demand component of the pricing structure varied between winter and summer. The energy portion was held constant for the year. The basis for setting the demand component of the price higher for the winter months was the September 1984 study of Marginal Time of Use (TOU) Costs. That study indicated that the seasonality of load affected costs whereby the ratio of winter costs to summer costs was 1.5.

To factor seasonal TOU into avoided costs, the Loss of Load Expectation (LOLE) index was used to allocate the capacity component of costs throughout the year. This resulted in a distribution of capacity costs of 60% during November to March and 40% for the remaining months.